

**BEFORE THE
PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA**

DOCKET NO. 2020-__-E

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In the Matter of:)
)
Duke Energy Carolinas, LLC's)
Establishment of Solar Choice Metering)
Tariffs Pursuant to S.C. Code Ann. Section)
58-40-20)
)
Duke Energy Progress, LLC's)
Establishment of Solar Choice Metering)
Tariffs Pursuant to S.C. Code Ann. Section)
58-40-20)

**DIRECT TESTIMONY OF
BRADLEY HARRIS FOR DUKE
ENERGY CAROLINAS, LLC AND
DUKE ENERGY PROGRESS, LLC**

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley (“Brad”) Harris, and my business address is 411 Fayetteville Street, Raleigh, North Carolina 27601.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Corporation as a Rates and Regulatory Strategy Manager, where I am responsible for managing strategic rate design reforms in the Carolinas and Florida.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor’s Degree in Political Science and Economics from Tufts University in 2013, a Master of Business Administration from the University of North Carolina Kenan-Flagler Business School in 2019 with concentrations in energy and corporate finance, and a Masters in Public Policy from Duke University’s Sanford School of Public Policy in 2019. At Duke University, I received the Outstanding Master’s Project Award for my consulting project for Duke Energy Corporation and my thesis, which was focused on residential rate design in North Carolina. From August 2014 – July 2015, I served as a registered lobbyist for the Friends Committee on National Legislation. From January 2016 – August 2016, I served as a Legislative Intern for Financial Services and Tax Policy with the United States Senate. In July 2019, after serving as a Graduate Fellow at the UNC School of Government and completing an MBA internship at Hannon Armstrong Sustainable Real Estate, I joined Duke Energy Corporation as a Senior

1 Pricing and Regulatory Solutions Analyst in July 2019. In January 2020, I assumed
 2 my current role as a Rates and Regulatory Strategy Manager, which includes
 3 responsibilities covering strategic rate design projects.

4 **Q. HAVE YOU TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION**
 5 **OF SOUTH CAROLINA (THE “COMMISSION”) IN ANY PRIOR**
 6 **PROCEEDINGS?**

7 A. I submitted testimony before the Commission in Docket No. 2019-182-E (the
 8 “Generic Docket”)—which is a generic docket established by the Commission
 9 pursuant to Act 62—on behalf of Duke Energy Carolinas, LLC (“DEC”) and Duke
 10 Energy Progress, LLC (“DEP” and together with DEC, the “Companies”).¹

11 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

12 A. I will provide an overview of the methodology utilized in the Companies’ cost of
 13 service analyses of the net energy metering (“NEM”) tariffs proposed under S.C.
 14 Act No. 62 of 2019 (“Act 62”). These analyses demonstrate the costs and benefits
 15 of the Companies’ proposed solar choice metering riders and rate schedules (the
 16 “Solar Choice Tariffs”)² presented by the Companies’ Application and discussed
 17 in greater detail by the Companies’ Witness Huber. As such, I will describe how
 18 these analyses were a key element in the development of the Solar Choice Tariffs,
 19 and I will also explain how these analyses support and justify the terms and
 20 conditions of the Solar Choice Tariffs and the Stipulation filed simultaneously
 21 herewith (the “Stipulation”).

¹ The hearing is scheduled to begin on November 17, 2020.

² These tariffs consist of the Interim Riders, Permanent Riders, Residential Solar Rate Schedules, and Non-Residential Riders, as defined in the Companies’ Application.

1 **Q. ARE YOU INCLUDING ANY EXHIBITS IN SUPPORT OF YOUR**
2 **TESTIMONY?**

3 A. Yes, **Harris Direct Exhibit 1** provides the Companies’ embedded cost of service
4 studies (collectively, the “Embedded Cost to Serve Studies”) with respect to the
5 Solar Choice Tariffs, **Harris Direct Exhibit 2** provides the Companies’ marginal
6 cost studies (collectively, the “Marginal Costs Studies”) with respect to the Solar
7 Choice Tariffs, and **Harris Exhibit 3** displays a list of rates for the proposed Solar
8 Choice Tariffs.

9 **Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR TESTIMONY.**

10 A. The Companies’ proposed Solar Choice Tariffs embody the fundamental principles
11 of Act 62. Key among those principles is that the tariffs should eliminate cost shift
12 or subsidization to “the greatest extent practicable,”³ while also employing a
13 methodology to compensate customer-generators for the benefits provided by their
14 generation to the power system.⁴ This topic is especially relevant because the
15 Commission is currently undergoing an evaluation of the Companies’ current NEM
16 programs (the “Existing NEM Programs”) in the Generic Docket. Although the
17 hearing is upcoming in that docket, the Companies and other intervenors have
18 already submitted testimony evidencing the results of a cost-benefit analysis of the
19 Existing NEM Programs required by Act 62, which revealed a cost-shift and
20 subsidization arising under those programs.⁵

³ S.C. Code Ann. § 58-40-20 (G)(1).

⁴ S.C. Code Ann. § 58-40-20 (F)(3).

⁵ Direct Testimony of Brian Horii, Docket No. 2019-182-E, p. 13, lines 18-19.

In developing the rates for the proposed Solar Choice Tariffs, the Companies not only leveraged the analyses in the Generic Docket, but also performed a similar analysis of the proposed Solar Choice Tariffs to ensure a meaningful comparison. The Companies' analyses of the proposed Solar Choice Tariffs show a stark improvement over the Existing NEM Programs, and greatly eliminate the unwarranted cost-shift through mechanisms such as time of use ("TOU") rates, a minimum bill, non-bypassable charges, and a basic facilities charge ("BFC"). The values for these components of the tariffs were developed through a careful, sound analysis—which utilized a Cost Duration Methodology—to ensure the next generation of NEM under Act 62 adequately aligns rates with the Companies' cost to serve NEM customers, thereby fulfilling Act 62's mandate to eliminate cost shift and subsidization "to the greatest extent practicable,"⁶ while also utilizing a methodology to compensate customer-generators for the benefits provided by their generation to the power system.⁷

II. COST OF SERVICE ANALYSES

Q. PLEASE PROVIDE AN OVERVIEW OF THE COST OF SERVICE ANALYSES THAT THE COMPANIES PERFORMED WITH REGARD TO THE SOLAR CHOICE TARIFFS.

A. By way of background, as required by Act 62, the Companies provided the Commission with cost of service studies of the Companies' Existing NEM Programs in the Generic Docket. Those studies viewed certain costs and benefits

⁶ S.C. Code Ann. § 58-40-20 (G)(1).

⁷ S.C. Code Ann. § 58-40-20 (F)(3).

1 of those programs under two different lenses—embedded costs and marginal costs.

2 Act 62 mandated that those studies account for the following factors:

- 3 (1) the aggregate impact of customer-generators on the electrical
- 4 utility's long-run marginal costs of generation, distribution, and
- 5 transmission;
- 6 (2) the cost of service implications of customer-generators on
- 7 other customers within the same class, including an evaluation of
- 8 whether customer-generators provide an adequate rate of return to
- 9 the electrical utility compared to the otherwise applicable rate class
- 10 when, for analytical purposes only, examined as a separate class
- 11 within a cost of service study;
- 12 (3) the value of distributed energy resource generation according
- 13 to the methodology approved by the commission in Commission
- 14 Order No. 2015-194;
- 15 (4) the direct and indirect economic impact of the net energy
- 16 metering program to the State; and
- 17 (5) any other information the commission deems relevant.
- 18

19 Although Act 62 only required these studies to be performed for the Existing NEM
 20 Programs, the Companies utilized the same factors—including utilizing the same
 21 underlying data, such as production meter data—in performing a forward-looking
 22 evaluation⁸ for the Companies' proposed Permanent Tariffs (as defined below). In
 23 this way, the Commission will be able to compare “apples to apples” when
 24 evaluating the Companies' Permanent Tariffs against the Existing NEM Programs.
 25 The outcome for each analysis is shown in **Harris Direct Exhibit 1** and **Harris**
 26 **Direct Exhibit 2**.

27 These analyses revealed that, in DEC's South Carolina service territory, the
 28 Permanent Tariffs—as outlined in the Stipulation—reduced the cross-subsidization
 29 by 88% under the Marginal Cost Studies, and 93%-113% in the Embedded Cost to

⁸ Order No. 2020-532, issued in Docket No. 2019-182-E on August 12, 2020, required a “Cost Benefit Analysis” in the Companies' application for the Solar Choice Tariffs.

1 Serve Studies. Considering both paradigms, the Stipulation reduces the cross-
 2 subsidy in DEC substantially, if not completely, and thus satisfies Act 62's
 3 requirement to reduce it "to the greatest extent practicable."⁹

4 In DEP's South Carolina service territory, the Permanent Tariffs—as
 5 outlined in the Stipulation—reduced the cross-subsidization by 53% under the
 6 Marginal Cost Studies and 109%-145% under the Embedded Cost to Serve Studies.
 7 The estimated ranges in DEP are further apart than the same estimates for DEC
 8 because there are different marginal and embedded cost structures in DEP's South
 9 Carolina service territory. Nevertheless, since the embedded cross-subsidy is over-
 10 corrected, while the marginal cross-subsidy is under-corrected, from a
 11 comprehensive perspective, the reduction in cross-subsidization appears to be in
 12 the correct range. At a minimum, the Permanent Tariffs significantly reduce cross-
 13 subsidization under each of the scenarios studies. This confirms that the Stipulation
 14 and resulting Solar Choice Tariffs achieve a key goal of Act 62 by reducing cost
 15 shift and subsidization "to the greatest extent practicable."¹⁰

16 **III. METHODOLOGY AND SUPPORT**

17 **Q. PLEASE PROVIDE A HIGH-LEVEL OVERVIEW OF THE RATE**
 18 **STRUCTURES WITHIN THE SOLAR CHOICE TARIFFS.**

19 **A.** The Companies' Witness Huber provides a detailed explanation of the rate
 20 structures utilized within the Solar Choice Tariffs, and how these rate structures
 21 utilized best-practices from other jurisdictions to fulfill the mandates of Act 62. At

⁹ S.C. Code Ann. § 58-40-20 (G)(1).

¹⁰ Id.

1 a high-level, the Companies will offer interim solar choice riders (the “Interim
2 Riders”) for residential customers applying for the Solar Choice Program from June
3 1, 2021, through and including December 31, 2021. After January 1, 2022,
4 residential customers applying for the Solar Choice Program will be placed upon
5 the Companies’ permanent solar choice rate schedules (the “Residential Solar Rate
6 Schedules”) and permanent riders (the “Permanent Riders” and together with the
7 Residential Solar Rate Schedules, the “Permanent Tariffs”).

8 The Permanent Tariffs are the keystones of the Companies’ Solar Choice
9 Program, and include TOU rates, critical peak pricing (“CPP”), a monthly
10 minimum bill, a BFC, and a grid access fee (“GAF”). As described by the
11 Companies’ Witness Huber, these rate mechanisms work in conjunction to achieve
12 the mandates within Act 62, and these tariffs will be available to customer
13 generators applying for interconnection after December 31, 2021.

14 **Q. PLEASE LIST THE RATES IN THE PROPOSED SOLAR CHOICE**
15 **TARIFFS.**

16 **A. Harris Direct Exhibit 3** lists the rates included in each of the Solar Choice Tariffs,
17 the billing determinants to which the charges are applied, and a brief description of
18 how the rates were determined.

19 **Q. PLEASE DESCRIBE HOW THE ENERGY CHARGES IN THE**
20 **PERMANENT TARIFFS WERE DETERMINED.**

21 **A.** The Companies used what we have termed a “Cost Duration Method” to identify
22 pricing appropriate for the TOU periods in the Permanent Tariffs. The Cost
23 Duration Method establishes a forecast of hourly system cost allocations.

1 Establishing accurate hourly system costs is a critical part of developing pricing for
2 TOU periods because the TOU rates must reflect the hourly costs to ensure that the
3 rates (1) better reflect the Companies' actual cost to serve by accurately
4 incorporating cost-causation in the TOU rates, and (2) send accurate, time-
5 differentiated price signals to customers to encourage electricity usage in non-peak
6 times in order to benefit the overall system.

7 **Q. CAN YOU PLEASE PROVIDE A HIGH-LEVEL OVERVIEW OF THE**
8 **COST DURATION METHOD THAT WAS UTILIZED TO DEVELOP THE**
9 **TOU RATES IN THE PERMANENT TARIFFS?**

10 A. The "Cost Duration Method" provides improved linkage between recovery of
11 system costs and the time periods during which system assets are being utilized.
12 For all three major utility functions (generation, transmission, and distribution),
13 some assets are only used to meet demand during a small number of "peak" hours,
14 while other assets are used for all or nearly all hours. The Cost Duration Method
15 allocates costs for assets across all three functions based on anticipated utilization.
16 Costs for assets used during all hours are assigned accordingly, while cost for assets
17 used during only peaking hours are concentrated in those hours (e.g. late afternoon
18 hours).

19 Because generation, transmission, and distribution demands are not
20 perfectly coincident, costs for each function were distributed independently, using
21 specific load duration curves. Generation and transmission capacity costs were
22 allocated using gross system load duration, and distribution capacity costs were
23 allocated using a distribution load duration curve for residential customer only. The

1 following five steps outline the cost allocation process that was used to develop the
2 TOU periods for each function using its respective load duration curve.

3 Step 1: Capacity costs were divided by the peak load of each load duration
4 curve to find a unit cost per MW of capacity.

5 Step 2: The incremental load in each hour was calculated by taking the
6 difference in load between that hour and the hour with the next highest load.
7 For the lowest load hour of the year, the load in that hour is used. Note that
8 the sum of all these incremental load amounts is necessarily equal to the
9 peak load.

10 Step 3: For each hour, the incremental load was shared evenly between the
11 hour in question and all hours of the year that have a higher load than the
12 hour in question. The incremental load at the highest load hour was not
13 shared as there are no higher load hours. The incremental load at the second
14 highest hour was shared evenly between the top two hours, and so forth.

15 Step 4: Next, load allocated to each hour was totaled. The highest load
16 hour has a share of load for all hours of the year, the second highest load
17 hour has a share of load for all hours of the year except the highest hour,
18 and so forth.

19 Step 5: Finally, the load allocated to each hour in Step 4 was multiplied by
20 the unit cost calculated in Step 1 to calculate the total cost of each hour.
21 This can in turn be divided by the billing load in that hour to calculate the
22 unit cost of each hour, which is used to determine the price ratios between
23 peak, off-peak, and super-off-peak periods. Multiplying by the revenue

1 requirement results in the per kWh prices for each TOU period.

2 **Q. PLEASE DESCRIBE THE PURPOSE OF CPP RATES IN THE**
3 **RESIDENTIAL SOLAR RATE SCHEDULES.**

4 A. These rates were negotiated among the parties to the Stipulation, and reflect the
5 Companies' increased cost to serve customers during times when the strain on the
6 system is the greatest—even to a degree over and above on-peak periods. A CPP
7 price of 25 cents/kWh is estimated to recover 35% and 37% of peak generation and
8 transmission costs in DEC and DEP respectively. The exact CPP determination
9 needed to balance multiple competing considerations including, how sensitive the
10 CPP revenue is to weather on only a few days, the likelihood of high-load days on
11 weekends, and customer acceptance of peak-time pricing (i.e. the effect “surge”
12 pricing has on customer satisfaction). The signatories of the Stipulation agreed that
13 the 25 cent/kWh CPP price reflected an appropriate and just balancing of these
14 priorities.

15 **Q. PLEASE DESCRIBE HOW THE COMPANIES DEVELOPED THE NON-**
16 **BYPASSABLE CHARGES IN THE RESIDENTIAL SOLAR RATE**
17 **SCHEDULES.**

18 A. As described by the Companies' Witness Huber, these non-bypassable charges are
19 designed to recover costs related to demand side management, energy efficiency,
20 storm cost recovery, and cyber security. These costs are incurred in serving NEM
21 customers but are not accurately captured in volumetric rates. In developing the
22 non-bypassable charges for the Residential Solar Rate Schedules, the Companies
23 utilized the production meter data that served as the basis for the analysis in the

Generic Docket to determine the total number of kWh that bypass the applicable riders (i.e. energy produced from solar minus net exports kWh's credited at avoided cost). This resulted in 9,598 kWh's under the netting policies proposed in the Permanent Riders. This number was multiplied by the rate of the non-bypassable costs and then divided by the average nameplate capacity of the sample of customers from the production meter data to arrive at the non-bypassable charge per year. Dividing by twelve resulted in the non-bypassable charge per month. The same process was used to determine the non-bypassable charge for the Interim Riders, except the kWh that bypass riders was 11,350 kWh due to the different netting policies.

Q. PLEASE DESCRIBE HOW THE COMPANIES DEVELOPED THE GAF IN THE RESIDENTIAL SOLAR RATE SCHEDULES.

A. The GAF recovers distribution costs of customers with system sizes greater than 15 kW-dc, which are larger-than-average systems. The unit cost from the relevant cost of service studies was multiplied by average maximum demand for customer-generators with greater than 15 kW-dc to estimate the total distribution costs per customer. The GAF is set to the level that would recover this cost minus the portion already recovered through the minimum bill.

Q. PLEASE DESCRIBE HOW THE BFCS IN THE RESIDENTIAL SOLAR RATE SCHEDULES WERE DETERMINED.

A. The BFCs matched the BFCs in the existing TOU rate schedules in each jurisdiction. Therefore, the BFC in DEC's Residential Solar Rate Schedule is equal

1 to that in rate schedule RT, while the BFC in DEP's Residential Solar Rate
2 Schedule is equal to that in rate schedule R-TOUD.

3 **Q. HOW DID THE COMPANIES DEVELOP THE VALUE PLACED UPON**
4 **MONTHLY NET EXPORTS?**

5 A. Monthly net exports are credited at an annualized rate (weighted average rate for
6 all hours assuming a fixed block of energy) for avoided energy costs as specified
7 by the per kWh and charges in Schedule Purchased Power in DEC and DEP.

8 **IV. CONCLUSION**

9 **Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

10 A. Yes, it does.

Embedded Cost Study
Docket No. 2019-182-E
Summary of Results and Rider Adjustments
For the test year ending December 31, 2017

DEP

	RES	RES Settlement
Monthly Cross-Subsidy Range	\$30-\$41	(\$3)-(\$13)
Estimated Reduction in Cross-Subsidy		109%-145%

DEC

	RS	RE	RS Settlement	RE Settlement
Monthly Cross-Subsidy Range	\$36-\$47	\$23-\$32	\$2-\$11	(\$7)-(\$15)
Estimated Reduction in Solar Cross-Subsidy			77%-95%	121%-166%

Settlement Weighted Reduction in Solar Cross-Subsidy **93%-113%**

Embedded Cost Study
Docket No. 2019-182-E
Summary of Results and Rider Adjustments
For the test year ending December 31, 2017

3% Sensitivity Factor for High/Low Scenarios
Applied to NEM CoS, Revenue Reduction, and Avoided Cost Payout

DEP													
	RES	RES - High	RES - Low	RES Settlement	RES Settlement - High	RES Settlement - Low	Notes						
Non-Net Metering Annual Cost-of-Service	\$ 1,827.29	\$ 1,827.29	\$ 1,827.29	\$ 1,827.29	\$ 1,827.29	\$ 1,827.29	All-in CoS for Customers before solar. Equals costs calculated in Calculations tab plus rider adjustments						
Net Metering Annual Cost-of-Service	\$ 1,005.03	\$ 1,035.18	\$ 974.88	\$ 1,005.03	\$ 1,035.18	\$ 974.88							
Cost-of-Service Reduction from Solar	\$ 822.26	\$ 792.11	\$ 852.41	\$ 822.26	\$ 792.11	\$ 852.41	All-in CoS for Customers after solar. Equals costs calculated in Calculations tab plus rider adjustments						
Cost-of-Service Reduction from Solar	\$ 822.26	\$ 792.11	\$ 852.41	\$ 822.26	\$ 792.11	\$ 852.41							
Revenue Reduction	\$ 1,266.28	\$ 1,304.27	\$ 1,228.29	\$ 837.62	\$ 862.75	\$ 812.49	Calculated from SAS model, used 2017 data set to match CoS test year, current rates						
Payout for Exports	\$ 23.68	\$ 22.97	\$ 24.39	\$ 116.13	\$ 112.64	\$ 119.61							
Net Revenue Reduction	\$ 1,242.60	\$ 1,281.30	\$ 1,203.90	\$ 721.49	\$ 750.11	\$ 692.88	Removed exports from calculation at unit cost						
Annual Solar Cross-Subsidy*	\$ 420.34	\$ 489.19	\$ 351.49	\$ (100.77)	\$ (42.00)	\$ (159.53)							
Monthly Solar Cross-Subsidy*	\$ 35.03	\$ 40.77	\$ 29.29	\$ (8.40)	\$ (3.50)	\$ (13.29)	Revenue reduction not including exports						
Reductoin in Solar Cross-Subsidy				124%	109%	145%							
DEC													
	RS	RS-High	RS- Low	RE	RE- Low	RE-High	RS Settlement	RS Settlement - High	RS Settlement - Low	RE Settlement	RE Settlement - High	RE Settlement - Low	
Non-Net Metering Annual Cost-of-Service	\$ 1,593.48	\$ 1,593.48	\$ 1,593.48	\$ 1,593.48	\$ 1,593.48	\$ 1,593.48	\$ 1,593.48	\$ 1,593.48	\$ 1,593.48	\$ 1,593.48	\$ 1,593.48	\$ 1,593.48	
Net Metering Annual Cost-of-Service	\$ 855.23	\$ 880.89	\$ 829.58	\$ 855.23	\$ 880.89	\$ 829.58	\$ 855.23	\$ 880.89	\$ 829.58	\$ 855.23	\$ 880.89	\$ 829.58	
Cost-of-Service Reduction from Solar	\$ 738.25	\$ 712.59	\$ 763.91	\$ 738.25	\$ 712.59	\$ 763.91	\$ 738.25	\$ 712.59	\$ 763.91	\$ 738.25	\$ 712.59	\$ 763.91	
Cost-of-Service Reduction from Solar	\$ 738.25	\$ 712.59	\$ 763.91	\$ 738.25	\$ 712.59	\$ 763.91	\$ 738.25	\$ 712.59	\$ 763.91	\$ 738.25	\$ 712.59	\$ 763.91	
Revenue Reduction	\$ 1,249.30	\$ 1,286.78	\$ 1,211.82	\$ 1,082.94	\$ 1,115.43	\$ 1,050.45	\$ 882.68	\$ 909.16	\$ 856.20	\$ 675.04	\$ 695.29	\$ 654.79	
Payout for Exports	\$ 13.80	\$ 13.39	\$ 14.22	\$ 13.80	\$ 13.39	\$ 14.22	\$ 67.70	\$ 65.67	\$ 69.73	\$ 67.70	\$ 65.67	\$ 69.73	
Net Revenue Reduction	\$ 1,235.50	\$ 1,273.39	\$ 1,197.60	\$ 1,069.14	\$ 1,102.04	\$ 1,036.23	\$ 814.98	\$ 843.49	\$ 786.47	\$ 607.34	\$ 629.62	\$ 585.06	
Annual Solar Cross-Subsidy*	\$ 497.25	\$ 560.80	\$ 433.70	\$ 330.89	\$ 389.45	\$ 272.33	\$ 76.73	\$ 130.90	\$ 22.57	\$ (130.91)	\$ (82.97)	\$ (178.84)	
Monthly Solar Cross-Subsidy*	\$ 41.44	\$ 46.73	\$ 36.14	\$ 27.57	\$ 32.45	\$ 22.69	\$ 6.39	\$ 10.91	\$ 1.88	\$ (10.91)	\$ (6.91)	\$ (14.90)	
Reduction in Cross-Subsidy							85%	77%	95%	140%	121%	166%	
Percent of Population	RS	RE	RS Settlement	RE Settlement	RS Settlement - High	RE Settlement - High	RS Settlement - Low	RE Settlement - Low					
Weighted Solar Cross-Subsidy		55%	45%	55%	45%	55%	45%	55%					
Weighted Reduction in Solar Cross-Subsidy		\$ 43.82		\$ (1.39)		\$ 2.89		\$ (5.67)					
				103%		93%		113%					
Rider Adjustments - DEC													
Notes													
EE/EDIT	\$	0.000946											
Fuel Adjustment from 2017-9/20	\$	(0.002664)	Embedded unit costs include fuel rate from 2017, need to update to rates as of 10/1/20 = 0.016102-0.018769										
Monthly Leaf 50C Charge		0.64											
Rider Adjustments - DEP													
Notes													
DSM/EE	\$	0.00671											
Fuel Adjustment from 2017-9/20	\$	(0.00282)	Embedded unit costs include fuel rate from 2017, need to update to rates as of 7/1/20 = 0.02456-0.03087										
EDIT	\$	(0.00349)											
Rider 39 Charge	\$	1.00											
Current NEM Policy Settlement													
Excess Exports kWh (i.e. kWh credited at avoided cost rate)		595	2,918										

Embedded Cost Study

Docket No. 2019-182-E

Calculation of Cost to Serve Without Adjustments

For the test year ending December 31, 2017

Unit Costs				
	unit	DEP	DEC	
P&T Demand	\$/kW-Month	\$ 16.91		
D Demand	\$/kW-Month	\$ 1.23	\$ 1.94	
P Demand	\$/kW-Month		\$ 15.31	
T Demand	\$/kW-Month		\$ 1.33	
Energy	\$/kWh	\$ 0.0398	\$ 0.0232	
Customer	\$/Month	\$ 27.46	\$ 24.85	
	\$	2.54	5.15	
		2.1	2.7	

DEP							DEC						
No Solar							No Solar						
Month	Energy	D Demand	P&T Demand	Customer	Total COS		Month	Energy	D Demand	T Demand	P Demand	Customer	Total COS
1	\$ 48.59	\$ 12.68	\$ 62.24	\$ 27.46	\$ 150.97		1	\$ 28.33	\$ 20.03	\$ 4.89	\$ 56.35	\$ 24.85	\$ 134.44
2	\$ 36.11	\$ 12.68	\$ 62.24	\$ 27.46	\$ 138.49		2	\$ 21.05	\$ 20.03	\$ 4.89	\$ 56.35	\$ 24.85	\$ 127.17
3	\$ 42.18	\$ 12.68	\$ 62.24	\$ 27.46	\$ 144.56		3	\$ 24.59	\$ 20.03	\$ 4.89	\$ 56.35	\$ 24.85	\$ 130.71
4	\$ 36.17	\$ 12.68	\$ 62.24	\$ 27.46	\$ 138.55		4	\$ 21.08	\$ 20.03	\$ 4.89	\$ 56.35	\$ 24.85	\$ 127.20
5	\$ 44.35	\$ 12.68	\$ 62.24	\$ 27.46	\$ 146.73		5	\$ 25.85	\$ 20.03	\$ 4.89	\$ 56.35	\$ 24.85	\$ 131.97
6	\$ 56.57	\$ 12.68	\$ 62.24	\$ 27.46	\$ 158.95		6	\$ 32.98	\$ 20.03	\$ 4.89	\$ 56.35	\$ 24.85	\$ 139.09
7	\$ 74.13	\$ 12.68	\$ 62.24	\$ 27.46	\$ 176.52		7	\$ 43.22	\$ 20.03	\$ 4.89	\$ 56.35	\$ 24.85	\$ 149.34
8	\$ 66.29	\$ 12.68	\$ 62.24	\$ 27.46	\$ 168.68		8	\$ 38.65	\$ 20.03	\$ 4.89	\$ 56.35	\$ 24.85	\$ 144.76
9	\$ 48.57	\$ 12.68	\$ 62.24	\$ 27.46	\$ 150.96		9	\$ 28.32	\$ 20.03	\$ 4.89	\$ 56.35	\$ 24.85	\$ 134.43
10	\$ 40.36	\$ 12.68	\$ 62.24	\$ 27.46	\$ 142.74		10	\$ 23.53	\$ 20.03	\$ 4.89	\$ 56.35	\$ 24.85	\$ 129.65
11	\$ 41.82	\$ 12.68	\$ 62.24	\$ 27.46	\$ 144.21		11	\$ 24.38	\$ 20.03	\$ 4.89	\$ 56.35	\$ 24.85	\$ 130.50
12	\$ 56.61	\$ 12.68	\$ 62.24	\$ 27.46	\$ 158.99		12	\$ 33.00	\$ 20.03	\$ 4.89	\$ 56.35	\$ 24.85	\$ 139.12
Total	\$ 591.76	\$ 152.18	\$ 746.94	\$ 329.46	\$ 1,820.34		Annual Total	\$ 344.98	\$ 240.32	\$ 58.67	\$ 676.24	\$ 298.18	\$ 1,618.39
Energy D Demand P&T Demand Customer Total COS							Energy D Demand T Demand P Demand Customer Total COS						
CoS Savings	\$ 191.39	\$ 9.13	\$ 635.30	\$ -	\$ 835.82		CoS Savings	\$ 111.58	\$ 14.41	\$ 49.91	\$ 575.17	\$ -	\$ 751.06
% Savings	32%	6%	85%	0%	46%		% Savings	32%	6%	85%	85%	0%	46%
Net Metering							Net Metering						
Month	Energy	D Demand	P&T Demand	Customer	Total COS		Month	Energy	D Demand	T Demand	P Demand	Customer	Total COS
1	\$ 40.06	\$ 11.92	\$ 9.30	\$ 27.46	\$ 88.74		1	\$ 23.36	\$ 18.83	\$ 0.73	\$ 8.42	\$ 24.85	\$ 76.18
2	\$ 26.41	\$ 11.92	\$ 9.30	\$ 27.46	\$ 75.09		2	\$ 15.40	\$ 18.83	\$ 0.73	\$ 8.42	\$ 24.85	\$ 68.22
3	\$ 29.37	\$ 11.92	\$ 9.30	\$ 27.46	\$ 78.05		3	\$ 17.12	\$ 18.83	\$ 0.73	\$ 8.42	\$ 24.85	\$ 69.95
4	\$ 22.83	\$ 11.92	\$ 9.30	\$ 27.46	\$ 71.51		4	\$ 13.31	\$ 18.83	\$ 0.73	\$ 8.42	\$ 24.85	\$ 66.14
5	\$ 26.41	\$ 11.92	\$ 9.30	\$ 27.46	\$ 75.09		5	\$ 15.39	\$ 18.83	\$ 0.73	\$ 8.42	\$ 24.85	\$ 68.22
6	\$ 33.02	\$ 11.92	\$ 9.30	\$ 27.46	\$ 81.70		6	\$ 19.25	\$ 18.83	\$ 0.73	\$ 8.42	\$ 24.85	\$ 72.08
7	\$ 43.20	\$ 11.92	\$ 9.30	\$ 27.46	\$ 91.88		7	\$ 25.18	\$ 18.83	\$ 0.73	\$ 8.42	\$ 24.85	\$ 78.01
8	\$ 41.35	\$ 11.92	\$ 9.30	\$ 27.46	\$ 90.03		8	\$ 24.11	\$ 18.83	\$ 0.73	\$ 8.42	\$ 24.85	\$ 76.93
9	\$ 30.39	\$ 11.92	\$ 9.30	\$ 27.46	\$ 79.06		9	\$ 17.71	\$ 18.83	\$ 0.73	\$ 8.42	\$ 24.85	\$ 70.54
10	\$ 28.48	\$ 11.92	\$ 9.30	\$ 27.46	\$ 77.16		10	\$ 16.61	\$ 18.83	\$ 0.73	\$ 8.42	\$ 24.85	\$ 69.43
11	\$ 32.29	\$ 11.92	\$ 9.30	\$ 27.46	\$ 80.97		11	\$ 18.82	\$ 18.83	\$ 0.73	\$ 8.42	\$ 24.85	\$ 71.65
12	\$ 46.56	\$ 11.92	\$ 9.30	\$ 27.46	\$ 95.24		12	\$ 27.14	\$ 18.83	\$ 0.73	\$ 8.42	\$ 24.85	\$ 79.97
Total	\$ 400.37	\$ 143.06	\$ 111.63	\$ 329.46	\$ 984.52		Annual Total	\$ 233.40	\$ 225.91	\$ 8.77	\$ 101.07	\$ 298.18	\$ 867.33

Embedded Cost Study
Docket No. 2019-182-E
Billing Determinants
For the test year ending December 31, 2017

Month	Sum of Exports	Sum of Imports	Sum of Self-Consumption	Gross Load (kWh)	Solar Production
1	399	1,007	203	1,221	601
2	655	664	230	907	885
3	890	738	312	1,060	1,202
4	857	574	329	909	1,186
5	872	664	443	1,114	1,315
6	731	830	588	1,421	1,319
7	674	1,085	770	1,863	1,445
8	569	1,039	622	1,666	1,191
9	693	764	445	1,221	1,138
10	666	716	287	1,014	954
11	463	811	232	1,051	695
12	338	1,170	248	1,422	586
Total	7,807	10,060	4,709	14,870	12,516

Non-Coincident Peaks

Description

No Solar	10.34
Solar	9.72

Coincident Peaks

	DEP	DEC
Date & Time	7/13/17 5pm	8/17/17 3pm
No Solar	no data	3.68
Solar	no data	0.55

Note: because load data was only available for DEC, DEC peak determinants were used for both utilities.
The DEP peaks are listed above only for reference.

DEC Functional Revenue by Rate
Docket No. 2019-182-E
SC RETAIL COST OF SERVICE - PROPOSED - 1CP - COMPLIANCE FILING
From Docket No. 2018-319-E
For the test year ending December 31, 2017
Dollars in Thousands

RATE	TOTAL	Production Demand	Production Energy	Transmission	Dist-Substations	Dist-Pole,Tow,Fix	Dist-Conductors	Dist-Transformers	Dist-Other Local	OTHER	Total Distr Demand	Dist-Customer	Total Distribution	DISTRIBUTION		Total Dist Demand/
														DNCP	DNCP	
	a	b	c	d	e	f	g	h	i	b	j	k	l	m	n	
RS1	394,586	176,840	75,977	15,347	10,042	8,081	16,712	9,770	27	76,818	44,632	81,790	126,422	1,892,350	4.32	
RT	638	304	156	26	15	11	25	14	0	-	65	86	151	3,009	2.17	
RE1	307,307	118,006	68,096	10,236	10,273	7,826	17,117	9,470	361	28,983	45,048	65,921	110,969	1,966,086	2.29	
Total RS	702,531	295,151	144,229	25,609	20,331	15,919	33,854	19,253	388	105,802	89,745	147,797	237,542			
TOTAL RETAIL	1,706,789	787,120	486,938	68,908	36,659	29,741	63,254	27,612	22,589	#N/A	179,855	183,968	363,823	6,987,517	2.57	

	Cost (not in thousands)	Annual Units	Unit Cost per Month
Customer	\$ 147,797,289	5,947,908	\$ 24.85
P Demand	\$ 295,150,765	1,606,176	\$ 15.31
T Demand	\$ 25,609,064	1,606,176	\$ 1.33
D Demand	\$ 89,745,114	3,861,445	\$ 1.94
Energy	\$ 144,228,770	6,206,954,000	\$ 0.0232
overall total	\$ 702,531,002		

Total RS

MWHS AT METER
MWHS at Meter 6,206,954

NON-COINCIDENT PEAK
NCP 3,861,445

NUMBER OF CUSTOMERS
Number of Customers 495,659
(not in thousands)

PRODUCTION DEMAND
Production Demand 1,606,176 Souce: DEC Allocators from SC Retail Cost of Service- Proposed - 1CP - Compliance Filing

DEP Functional Revenue By Rate
Docket No. 2019-182-E
From DOCKET NO. 2018-218-E "ADJUSTED BY FUNCTION WITH COMPLIANCE RATES ANNUALIZED"
SOUTH CAROLINA RETAIL COST OF SERVICE STUDY
ADJUSTED TEST YEAR ENDING DECEMBER 31, 2017

UNIT DETAIL - REVENUES	Unit Cost Classification	SC RETAIL	SC RES excl TOU	SC RES TOU
FUNCT REQ'TS RATE SCHED REV incl.				
ASK: Incr. (Decr.)				
PROD_DEMAND	Product & Trans Demand	221,794,781	84,460,810	1,588,673
PROD_ENERGY	Energy	226,470,785	78,726,632	1,595,259
TRANSMISSION	Product & Trans Demand	24,061,158	8,765,785	159,600
DIST_SUBS	Distribution Demand	10,954,293	5,482,623	81,806
DIST_PRIMARY	Distribution Demand	12,047,505	6,631,195	99,719
DIST_L_XFMR	Distribution Demand	6,125,895	3,323,302	49,077
DIST_SEC_SERV	Distribution Demand	19,883,544	2,572,841	38,711
CUSTOMER	Customer	56,469,352	44,228,779	560,089
Total		577,807,313	234,191,968	4,172,933
Billing Determinants	Summer CP kW (DP adj @ meter)	1,610,108	458,926	8,994
	Adj kWh Sales (E2 at meter)	8,241,813,840	1,978,209,443	40,124,603
	Year End No. Cust (C1)	304,233	134,234	1,712

SC Res NCP CY 2017 1,241,969

	Unit Cost	Notes
Customer (\$/month)	\$ 27.46	Costs/Number of Customers
Distribution Demand (\$/kW-Month)	\$ 1.23	Costs/SC Res NCP CY 2017/12
Production and Trans Demand (\$/kW-Month)	\$ 16.91	Costs/Summer CP kW
Energy (\$/kWh)	\$ 0.03980	Costs/Adj kWh Sales

DEP

RES Marginal Cost	\$	64
Settlement RES Marginal	\$	30
Percent Reduction - Marginal		53%

DEC

RS Marginal Cost	\$	43
Settlement RS Marginal	\$	14
RE Marginal Cost	\$	25
Settlement RE Marginal	\$	(8)
Weighted Average Marginal Cost	\$	35
Weighted Average Settlement Marginal	\$	4
Percent Reduction - Marginal		88%

	2021 DEC-SC System Benefits for RS Customers			
	Total NEM	Self-Service NEM	NEM Exports	
Annual kWh Production	10,907	10,316	591	
Avoided costs use prevailing values from DSM/EE mechanism				
Avoided Electric Production	\$286	\$270	\$15	
Avoided Electric Capacity	\$40	\$40	\$0	
Avoided Electric T&D	\$355	\$355	\$0	
2021 Total Benefits	\$681	\$665	\$15	

Notes

kWh comprised by self-service (consumed behind the meter) or exported on a monthly basis.

Includes Fuel + O&M to produce kWh

New Plant

New Transmission and Distribution

	RS Current	RS Settlement
Total Benefits	\$681	\$681
Revenue Reduction	\$1,197	\$850
Monthly Cross-Subsidy	\$43	\$14

Derived from SAS model of CY2019 NEM data

67%

Percent Reduction

	2021 DEC-SC System Benefits for RR Customers			
	Total NEM	Self-Service NEM	NEM Exports	
Annual kWh Production	13,209	12,547	662	
Avoided costs use prevailing values from DSM/EE mechanism				
Avoided Electric Production	\$346	\$329	\$17	
Avoided Electric Capacity	\$40	\$40	\$0	
Avoided Electric T&D	\$355	\$355	\$0	
Total Benefits	\$741	\$724	\$17	

Notes

kWh comprised by self-service (consumed behind the meter) or exported on a monthly basis.

Includes Fuel + O&M to produce kWh

New Plant

New Transmission and Distribution

	RE Current	RE Settlement
Total Benefits	\$741	\$741
Revenue Reduction	\$1,037	\$641
Monthly Cross-Subsidy	\$25	-\$8

Derived from SAS model of CY2019 NEM data

134% Percent Reduction

	DEC-SC NPV 2021\$		
	Total NEM	Self-Service NEM	NEM Exports
Annual kWh Savings	12,427	11,378	1,049
Avoided costs use prevailing values from DSM/EE mechanism			
Avoided Electric Production	\$313	\$286	\$26
Avoided Electric Capacity	\$2	\$2	
Avoided Electric T&D	\$124	\$124	
Total Benefits	\$438	\$412	\$26

Notes

kWh comprised by self-service (consumed behind the meter) or exported on a monthly basis.

Includes Fuel + O&M to produce kWh

New Plant

New Transmission and Distribution

	RES Current	RES Settlement
Total Benefits	\$438	\$438
Revenue Reduction	\$1,211	\$799
Monthly Cross-Subsidy	\$64	\$30

Derived from SAS model of CY2019 NEM data

53%

Percent Reduction

R-STOU

<u>Charge</u>	<u>Billing Determinant</u>	<u>DEC Rate</u>	<u>DEP Rate</u>	<u>Basis</u>
Basic Facilities Charge (BFC)	Per Customer	\$	13.09	\$ 14.63 BFC in existing TOU Rate Schedules
Energy Charges*	Per kWh in TOU period			
Critical Peak	Per Critical Peak kWh		25c	25c Negotiated
Peak	Per Peak kWh		15.1760c	15.844c Cost Duration Model
Off-Peak	Per Off-Peak kWh		8.7586c	9.529c Cost Duration Model
Super-Off-Peak	Per Super-Off-Peak kWh		6.0268c	6.994c Cost Duration Model
Grid Access Fee	Per kW-dc, only applies to kW over 15 kW-dc	\$	5.86	\$ 3.95 Distribution Cost for Systems over 15 kW-dc
Non-Bypassables	Per kW-dc	\$	0.42	\$ 0.49 Estimated Bypassed Riders
<i>Minimum Bill - Describes portion of energy charges that satisfy the minimum bill*</i>				
Customer & Distribution - Peak	Per Peak kWh		3.6569c	2.591c Cost Duration Model, Customer & Distribution only
Customer & Distribution - Off-Peak	Per Off-Peak kWh		2.4882c	1.951c Cost Duration Model, Customer & Distribution only
Customer & Distribution - Super-Off-Peak	Per Super-Off-Peak kWh		1.8066c	1.577c Cost Duration Model, Customer & Distribution only

I-NMSC

<u>Charge/Credit</u>	<u>Billing Determinant</u>	<u>DEC Rate</u>	<u>DEP Rate</u>	
Avoided Cost Rate			2.717c	2.303c Excess kWh exported (I.e. not netted)

NMSC

<u>Charge/Credit</u>	<u>Billing Determinant</u>	<u>DEC Rate</u>	<u>DEP Rate</u>	
Non-Bypassables		\$	0.50	\$ 0.58 Estimated Bypassed Riders
Avoided Cost Rate			2.717c	2.303c Excess kWh exported (I.e. not netted)

*rates include fuel but not riders